STATE OF MAINE
PUBLIC UTILITIES COMMISSION

Docket No. 2001-239

February 28, 2002

MAINE PUBLIC UTILITIES COMMISSION
Investigation of Bangor Hydro-Electric Company's Stranded Cost Revenue Requirement

ORDER APPROVING STIPULATION

WELCH, Chairman; NUGENT and DIAMOND, Commissioners

I. SUMMARY

In this Order, we approve a Final Amended Stipulation (also referred to as "the Stipulation") entered into between Bangor Hydro-Electric Company (BHE or Company), the Office of the Public Advocate (OPA) and the Industrial Energy Consumers Group (IECG) which establishes BHE's stranded cost revenue requirement for a 3-year period beginning March 1, 2002. Under the terms of the Final Amended Stipulation which we approve, stranded cost rates on average will increase by 18.9%. However, given the decrease in BHE's standard offer rates which we approved in Docket No. 2001-399, the bundled rates for the Company's residential and small commercial customers will decrease by slightly more than 10% on March 1, 2002. In addition, the Company's largest industrial customers who, as a result of long-term contracts, will not be able to take advantage of decreased supply costs will continue to receive rate mitigation although at a reduced rate from the level previously ordered in Docket No. 97-596.

II. PROCEDURAL HISTORY

See Appendix A.

III. BACKGROUND

On March 1, 2000, Maine consumers were provided with the opportunity to purchase generation services from the competitive market and, as of that date, the generation portion of electricity service was no longer subject to rate regulation in Maine. As a part of the Restructuring Act, the Commission was required to determine and permit recovery of each utility's stranded costs, defined to be the "legitimate, verifiable and unmitigable costs made unrecoverable as a result of the restructuring of the electric industry …." 35-A M.R.S.A. § 3208.

In *Public Utilities Commission, Investigation of Bangor Hydro-Electric Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements and Rate Design,* Docket No. 97-596 (BHE's so-called "megacase"), the Commission established transmission and distribution (T&D) rates for BHE which reflected a 2-year stranded cost revenue requirement. The 2-year period was chosen to coincide with the period of time for which BHE had sold its non-divested generation asset entitlements pursuant to Chapter 307 of the Commission's Rules. By way of orders dated March 28, 2001 and May 7, 2001, we reduced BHE's T&D rates by .8¢/kWh for those customers that fell within the Company's large standard offer class to mitigate the impact of significant increases in generation prices whether from standard offer service or from competitive providers. *Public Utilities Commission, Investigation of Bangor Hydro-Electric Company's Stranded Costs, Transmission and Distribution Utility Revenue Requirements and Rate Design,* Docket No. 97-596 Order (March 28, 2001) and Order on Reconsideration (May 7 2001). The .8¢/kWh mitigation was to be funded through an allocation of the Company's Asset Sale Gain Account (ASGA).[1] The mitigation went into effect on April 15, 2001 and will expire on February 28, 2002.

Given the pending expiration of BHE's initial sale of its entitlement output, the Commission initiated this case on May 8, 2001. As discussed in Section II, since much of the information needed to decide this case was not available at the time we initiated it, the schedule was segmented into several phases: Phase I was intended to facilitate identification of the major issues; Phase II would contain the utility sales forecast as well as projected rates based on illustrative Chapter 307 bid information; and Phase III would contain actual rate recommendations using the Chapter 307 bid information.

On September 19, 2001, the Commission accepted a contingent standard offer bid for BHE's residential and small commercial classes. As part of the decision to accept a contingent standard offer bid, an affiliate of the winning standard offer bidder also purchased BHE's non-divested entitlements for a 3-year period.[2] *Public Utilities Commission, Standard Offer Bidding Process,* Docket No. 2001-399, Order (Sept. 18, 2001). As a condition of the winning bid, the price that the winning bidder is to pay for the power supply entitlement was to be protected from disclosure until January 1, 2002.

On October 3, 2001, BHE submitted its Phase II filing, which contained its stranded cost revenue requirement proposals and calculations using proxy entitlement prices established by the Examiner in a Procedural Order dated September 28, 2001. On November 13, 2001, the OPA and the IECG filed testimony in response to the Company's case. On November 15, 2001, the Commission's Advisory Staff filed its Phase II Bench Analysis.

The Intervenors' testimony and the Staff's Bench Analysis raised the following issues regarding the Company's filing: the appropriateness of the Company's stranded

[1]The ASGA is a regulatory liability on the Company's books resulting from the over-book proceeds received from BHE's divestiture of its generation assets.

[2]In its Order on Reconsideration in Docket No. 2001-399 (Jan. 11, 2002), the Commission explained why it found that selling the non-divested generation asset entitlements as part of the standard offer process without a concurrent stand-alone Chapter 307 process was reasonable.

cost rate plan; the reasonableness of the Company's sales forecast; the calculation of the allowable deferral resulting from the Company's HoltraChem Manufacturing (HCM or HoltraChem) contract; the calculation of the return on stranded cost rate base items; the treatment of distributions received by Maine Yankee from Nuclear Electric Insurance Limited (NEIL); the treatment of standard offer revenues and costs; and the allocation of stranded costs among customer classes. The Bench Analysis also raised for future discussion with the Company the reasonableness of the Company's actions regarding the arbitration of the Sebec Hydro Qualifying Facility (QF) contract. On December 7, 2001, the Company submitted its Phase II rebuttal testimony.

On December 18, 2001, we received an initial stipulation entered into between the Company, the OPA and the IECG (collectively referred to as "Stipulating Parties"). On January 2, 2002, the Company, on behalf of the Stipulating Parties, submitted an amended stipulation and on January 4, 2002, the Company submitted an updated set of exhibits to the Amended Stipulation, which reflected BHE's actual costs for administering the standard offer through November 30, 2001, the inclusion of actual entitlement sales prices related to the Company's power supply entitlements, and the anticipated deferral of incremental legal costs associated with the Company's efforts to mitigate stranded costs related to its Sebec Hydro QF contract. In a letter to the Commission dated January 7, 2002, the Company clarified that the January 4th Update was not intended to further amend the January 2nd Amended Stipulation and that the numbers in the update were subject to later review by the parties and the Commission Staff.

At our January 14, 2002 deliberative session, in considering the January 2, 2002 Amended Stipulation, we expressed our concern over the design of the .4¢/kWh rate mitigation program for large customers and asked that the parties consider addressing these concerns by further amending the Amended Stipulation.

On January 15, 2002, we received a supplement to the Amended Stipulation which addressed our concerns about the rate mitigation program. At our January 16, 2002 deliberative session, we approved the revenue requirement and mitigation provisions of the Amended Stipulation, but we expressed concern about the lack of clarity on class cost allocation and rate design issues. We, therefore, directed the parties and our Staff to collaborate on rate design provisions consistent with our decision on the revenue requirement and mitigation issues.

On February 13, 2002, we received a Final Amended Stipulation which, working off the prior Amended Stipulation as supplemented, reflected modifications to the rate design methodologies and calculations resulting from the collaborative discussions among the Stipulating Parties and our Advisory Staff. The Final Amended Stipulation also incorporated the updated estimates of BHE's standard offer over-collections as reflected in the Company's January 4th filing. The Company's cover letter to the Final Amended Stipulation indicated that it had decided not to include the legal expenses associated with Sebec Hydro arbitration as part of stranded costs in the case and, therefore, no update was required for this issue.

As discussed in Section V, *infra., w*ith certain clarifications, we approve the Final Amended Stipulation submitted to us on February 13, 2002.

IV. DESCRIPTION OF THE STIPULATION

Under the terms of the Stipulation, stranded cost revenue requirements and rates would be established for a 3-year period beginning on March 1, 2002 and ending on February 28, 2005. During that time, however, the parties could file a request with the Commission for a prospective adjustment to the Company's stranded cost rates based on changes in sales levels or any other change in adjustable stranded cost revenue requirements.

The parties to the Stipulation rely on the Company's December 7th filing as the base case for their agreement. The revenue requirement adjusts the Company's base case for the following items:

> 1) Treatment of the HoltraChem Deferral – Authorizes the Company to defer and recover over four years $2,414,148 in revenue collected from HCM below the level expected in the Company's megacase;
> 2) NEIL – Flows through $1,147,882 of the NEIL refund to customers over a two-year period;
> 3) Return on Rate Base – Uses the pretax weighted average cost of capital determined in the megacase to calculate the return on all rate base items other than Maine Yankee and Ultrapower; and
> 4) Standard Offer Revenue – Establishes a regulatory liability of $6,921,322 associated with the estimated over-collection of net standard offer revenue through February 28, 2002.

The Stipulation establishes a revenue requirement of $44,234,493 in rate year 1; $39,994,185 in rate year 2; and $49,394,425 in rate year 3. To achieve rate stability during the 3-year rate effective period, rates are based on a levelized revenue requirement of $45,144, 768. Differences between the annual revenue requirement numbers and the levelized revenue requirement are deferred using a "Levelizer Account." Rates for the 3-year rate-effective period were based on the levelized revenue requirement and the level of sales forecast by the Company's witness Roger Cooper, and were allocated among classes using a 75/25 energy-demand split and using class energy consumption derived from the megacase billing determinants.

The Stipulation further provides that the Company's D-3 and D-4 customers will be eligible for a 4 mil/kWh discount off their total T&D rate during the first year of the rate-effective period to mitigate continued high generation costs that these customers will pay. Discounts provided under this mitigation program shall be treated as reductions to the Company's ASGA and shall be based on the actual billing determinants of eligible customers. Discounts under this program will be available to eligible customers with respect to any billing cycle just concluded during the rate mitigation year.

To qualify for the mitigation discount a customer must demonstrate that its average annual generation service price for the rate mitigation year is equal to or greater than 6¢/kWh. The customer's average annual generation price is to be determined using each of the following components: (1) the customer's actual generation service price and consumption for each preceding billing cycle during the rate mitigation year, and (2) a prospective estimate of the customer's generation service price and consumption during the remaining billing cycles in the rate mitigation year. For purposes of making prospective estimates of a customer's generation service price, the Company may rely on the price and term information provided by the customer seeking the discounts. For customers who do not have a contracted generation service price for the entire term of the rate mitigation year, the Company will assume that the price for the period contract will equal the customer's applicable standard offer rate. However, if a customer whose eligibility was based on the standard offer rate later enters into a generation service contract for some or all of the remaining period at a price that would qualify the customer for the discount, the customer will be entitled to any discounts as provided above, and will also be entitled to receive the value of the discount for any prior billing period during the rate mitigation year to which the customer becomes qualified on a retroactive basis.

The Stipulation also proposes an incentive mechanism to mitigate stranded costs which provides that savings from QF contract restructurings should be split 80/20 between ratepayers and shareholders over the life of the restructured contract. Each time stranded costs are reset, the savings for that stranded cost period will be subtracted from the total costs which would have been incurred had no restructuring taken place.

V. DECISION

As we have stated on numerous occasions, to approve a stipulation the Commission must find that:

1. the parties joining the stipulation represent a sufficiently broad spectrum of interests that the Commission can be sure that there is no appearance or reality of disenfranchisement;

2. the process that led to the stipulation was fair to all parties; and

3. the stipulated result is reasonable and not contrary to legislative mandate.

See Central Maine Power Company, Proposed Increase in Rates, Docket No. 92-345(II), Detailed Opinion and Subsidiary Findings (Me. P.U.C. Jan. 10, 1995), and

Maine Public Service Company, Proposed Increase in Rates (Rate Design), Docket No. 95-052, Order (Me. P.U.C. June 26, 1996).

We have also recognized that we have an obligation to ensure that the overall stipulated result is in the public interest. *See Northern Utilities, Inc., Proposed Environmental Response Cost Recovery,* Docket No. 96-678, Order Approving Stipulation (Me. P.U.C. April 28, 1997). We find that the proposed Stipulation in this case meets all of the above criteria.

In this case, the Stipulation was entered into by the Company, the OPA and the IECG. No other intervenor opposes the Stipulation. We find that the stipulating parties represent a sufficiently broad spectrum of interests to ensure that there was no appearance or reality of disenfranchisement.

There has not been any indication given by any intervenor or the Advisory Staff that the process in this matter was anything but fair. We thus find that our second criterion has also been satisfied.

In deciding whether a stipulation is fair and consistent with the public interest, the entire stipulation must be considered as a package. Whether we disagree with a particular stipulation provision or would have come up with a different resolution were we deciding the case after litigation is not the question. *Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post-merger) "ARP 2000*," Docket No. 99-666, Order Approving Stipulation at 13 (November 16, 2000). The question is whether the particular proposal before us is reasonable and consistent with the public interest. *See Docket No. 92-345 (Phase II), supra*., Order at 3. In deciding this question, any detriments which have been raised must be weighed against the benefits of the stipulation.

The Stipulation resolves the most controversial revenue requirement issues in the case (the flow-through of the NEIL refund and the calculation of the HoltraChem deferral) in a manner which we find to be reasonable and fair. All other revenue requirement issues are also resolved in a manner which is reasonable and consistent with the public interest. As discussed in Section III, *supra.*, during our deliberative sessions of January 14 and January 16, 2002, we noted our concerns with the initial methodology proposed by the parties to determine eligibility for the rate mitigation program and with initial rate design methodology proposed by the Stipulating Parties. These concerns have been adequately addressed in the Final Amended Stipulation.

We note that the mitigation methodology proposed in the Final Amended Stipulation is different from the mitigation methodology we recently approved for Central Maine Power Company in *Maine Public Utilities Commission, Investigation of Central Maine Power Company's Stranded Cost Revenue Requirement*, Docket No. 2001-232, Order Approving Stipulation (ME. P.U.C. February 15, 2002). In approving the CMP mitigation provision, we recognized the difficulty in designing a mitigation program which both addresses the problem of providing benefits to those customers who are not actually suffering from the impact of high generation costs and avoids Commission interference in the discipline of the competitive market. As we concluded in *Central Maine Power Company, Request for Approval of Alternative Rate Plan (Post-Merger) "ARP 2000,"* Docket No. 99-666, Order Approving Stipulation at 16 (Me. P.U.C. Nov. 6, 2000), there rarely is one acceptable resolution to the issues raised in cases litigated before us. Given BHE's circumstances (little available value remaining the Company's ASGA, high stranded cost rates and a smaller industrial customer base to monitor), we find the targeted approach agreed to by the parties in their Final Amended Stipulation to be reasonable.

We also find the class allocation provisions of the Final Amended Stipulation which reflect the collaborative effort of the parties and our Advisory Staff to be reasonable and consistent with public interest. We thus conclude that since the overall stipulated result is reasonable and consistent with the public interest and legislative mandate, the Final Amended Stipulation should be approved. Our approval of the Final Amended Stipulation, however, is based on the following interpretations of the Stipulation's provisions.

First, paragraph III(1)(f) of the Stipulation provides that the Company may defer for future recovery any differences between estimated standard offer net revenues and actual net revenues, once they become known. We interpret this provision to be reciprocal and that the Company *must* defer for future flow-through any under-estimates in net standard offer revenues. Second, while the Stipulating Parties have included the costs associated with the results of the Sebec Hydro arbitration, and we approve the overall revenue requirement which includes this assumption, our approval does not preclude either a future prudence investigation on this issue or a prospective adjustment to stranded costs based on the results of such an investigation. Third, the parties agreed that any future stranded cost proceeding brought during the 3-year rate effective period be concluded within 120 days. While the Commission will certainly endeavor to meet this goal in such a proceeding, we cannot absolutely commit to such a deadline since we cannot predict the complexity of these future proceedings. Fourth, the stranded cost mitigation incentive mechanism agreed to in the Stipulation provides that each time stranded costs are reset, savings will be subtracted from stranded costs. Consistent with the operation of the incentive mechanism which we recently approved for CMP in Docket No. 2001-232, we interpret this provision to mean that savings will be recalculated each time stranded costs are reset. Finally, paragraph III(12) of the Stipulation states that "unless otherwise provided in the Stipulation or the attached exhibits, the Company's pre-filed testimony of December 7, 2001, is hereby incorporated within the terms of this Stipulation." We understand that this provision refers solely to the schedules attached to the December 7th testimony and not the narrative since there are clearly several items in the narrative, such as the Company's rate plan proposal, which have neither been accepted or rejected by the Stipulation, and which we do not intend to accept by our approval of the Stipulation.

Based on the above interpretations and understandings, we approve the Final Amended Stipulation.

Accordingly, we

O R D E R

1. That the Final Amended Stipulation entered into between the Bangor Hydro-Electric Company, the Office of the Public Advocate and the Industrial Energy Consumers Group submitted to us on February 13, 2002 is hereby approved. A copy of the Stipulation is attached hereto and is incorporated by reference; and,

2. That BHE shall file rates in accordance with the terms of this Order Approving Stipulation. We delegate our authority to approve such rates filed in compliance with the terms of this Order to the Commission's Director of Technical Analysis.

Dated at Augusta, Maine, this 28th day of February, 2002.

BY ORDER OF THE COMMISSION

Raymond J. Robichaud
Assistant Administrative Director

COMMISSIONERS VOTING FOR: Welch
Nugent
Diamond

THIS DOCUMENT HAS BEEN DESIGNATED FOR PUBLICATION

NOTICE OF RIGHTS TO REVIEW OR APPEAL

5 M.R.S.A. § 9061 requires the Public Utilities Commission to give each party to an adjudicatory proceeding written notice of the party's rights to review or appeal of its decision made at the conclusion of the adjudicatory proceeding. The methods of review or appeal of PUC decisions at the conclusion of an adjudicatory proceeding are as follows:

1. Reconsideration of the Commission's Order may be requested under Section 1004 of the Commission's Rules of Practice and Procedure (65-407 C.M.R.110) within 20 days of the date of the Order by filing a petition with the Commission stating the grounds upon which reconsideration is sought.

2. Appeal of a final decision of the Commission may be taken to the Law Court by filing, within **21 days** of the date of the Order, a Notice of Appeal with the Administrative Director of the Commission, pursuant to 35-A M.R.S.A. § 1320(1)-(4) and the Maine Rules of Appellate Procedure.

3. Additional court review of constitutional issues or issues involving the justness or reasonableness of rates may be had by the filing of an appeal with the Law Court, pursuant to 35-A M.R.S.A. § 1320(5).

Note: The attachment of this Notice to a document does not indicate the Commission's view that the particular document may be subject to review or appeal. Similarly, the failure of the Commission to attach a copy of this Notice to a document does not indicate the Commission's view that the document is not subject to review or appeal.

APPENDIX A

On May 8, 2001, the Commission issued a Notice of Investigation initiating this docket. That Notice identified the likely issues to be addressed in this matter and also provided interested persons with an opportunity to intervene.

Timely petitions to intervene were filed by the Industrial Energy Consumers Group (IECG) and the Office of the Public Advocate (OPA). An oral petition to intervene was made by the Independent Energy Producers of Maine (IEPM) at the initial case conference held on May 23, 2001. There being no objections and good cause existing, the above-referenced petitions to intervene were all granted. In addition to the above-referenced petitions to intervene, the Commission received requests from Central Maine Power Company (CMP) and Bangor Gas Company, LLC (Bangor Gas) that they be added to the service list in this case as interested persons who receive copies of all filings. These requests were granted without objection subject to the terms set forth in a Procedural Order dated May 23, 2001 in Docket No. 2001-232.

A teleconference to discuss scheduling in this case was held on June 5, 2001. Based on the discussions at the conference, a schedule governing the first two phases of the case was established. As set forth in a Procedural Order of June 11, 2001, the Company's Phase I filing was to address:

1) Stranded cost class cost allocation methodology;

2) A proposal for the treatment of revenue from non-core customers;

3) A proposal for an appropriate QF incentive mechanism on a prospective basis;

4) A comparison of budgeted nuclear expense figures used in the stranded cost calculations developed in the rate case to actual nuclear expenses;

5) An explanation of BHE's plans with respect to the HQ tie line;

6) BHE's Fall 2000 sales forecast for the 3-year period 2001-2003 with a comparison to 2001 actual results;

7) A performance-based ratemaking proposal for resetting stranded cost prices and providing proper incentives;

8) An update of the ASGA balances including amounts amortized for targeted ASGA uses; and

9) Amounts deferred pursuant to the Commission's Order in Docket No. 97-596.

As part of its Phase II filing, the Company was to address:

1) QF cost data and volumes;

2) Illustrative energy price placeholders for the sale of the purchased power entitlements;

3) BHE's Fall 2001 sales forecast;

4) Current data regarding BHE's nuclear obligations;

5) Updated information regarding the HQ tie line; and

6) BHE's approach for rate design using illustrative bid revenue and forecasted billing units.

The schedule for Phase II of the case, which would incorporate the actual results of BHE's sale of output from its non-divested generation assets and the standard offer bid process, would be developed at a later date.

On July 16, 2001, BHE submitted its Phase I filing in this case. Technical conferences on the Company's Phase I filing were held on July 24, 2001 and on August 9, 2001. The Advisory Staff and the OPA filed comments on the Company's Phase I filing on August 16, 2001.

On September 19, 2001, Central Maine Power Company filed a letter with the Commission in its stranded cost revenue requirement case, Docket No. 2001-232, requesting a modification of the previously established schedule given the Commission's decision to accept a "linked" standard offer bid for residential and small commercial customer classes in Docket No. 2001-399. CMP argued that this decision obviated the need for a Phase III segment of the case and stated that with a slight extension of time to file, CMP could incorporate the standard offer and QF output prices into its filing. Bangor Hydro-Electric Company supported adoption of a similar revision in the schedule in this case.

By way of a Procedural Order issued on September 24, 2001, the requests of CMP and BHE to move the time for filing the utilities' Phase II case and the Phase I rebuttal from September 24, 2001 were granted. A conference of counsel to discuss the remainder of the schedule in these proceedings in light of the protective issues raised by the Commission's decision of September 18, 2001 in Docket No. 2001-399 was held on September 26, 2001. Under the terms of that protective order, access to actual bid price information was restricted to Commission members, Staff, members of the OPA and the affected T&D utilities until January 1, 2002. Given this restriction, the Examiners concluded that the utilities, in developing their Phase II filings, should use proxy entitlement sale numbers (expressed in $/mWh) for purposes of calculating and allocating stranded costs.

On October 3, 2001, the Company submitted its Phase II filing using the proxy prices established in the September 28, 2001 Procedural Order. BHE's Phase II filing consisted of the testimony of Peter Dawes/ David Black (revenue requirements), Roger Cooper (sales forecast), Mark Colca (rate design), Jeffrey Jones (purchased power and standard offer), and Mathieu Poulin (cost of capital and rate plan). A technical conference on the Company's case was held on November 1, 2001. On November 13, 2001, the OPA filed its reply case consisting of the testimony of Thomas Catlin and Steven Estomin. On that same date, the IECG filed the testimony of Richard Silkman. On November 15, 2001, the Advisory Staff filed its Phase II Bench Analysis.

On December 7, 2001, the Company filed its rebuttal case consisting of the testimony of Company witnesses Black/Dawes, Cooper, Colca, Poulin and Jones. On December 18, 2001, we received the initial stipulation entered into between the Company, the OPA and the Staff. A technical conference on the initial stipulation was held on December 21, 2001. On January 3, 2002, a hearing was held on the Amended Stipulation. On January 4, 2002, the Company submitted an updated filing, which among other things, updated the revenue from the Chapter 307 output sale with the actual sales numbers.

At our deliberative session of January 14, 2002, in considering the initial Stipulation, we expressed concern over the initial Stipulation's rate mitigation provision. On January 15, 2002, we received a supplement to the initial Stipulation to which the Stipulating Parties had agreed in order to address these concerns. At our January 16, 2002 deliberative session, we voted to approve the revenue requirement and mitigation provisions of the Amended Stipulation as supplemented but directed the Stipulating Parties to work with the Commission's Staff on clarifying rate design and class allocation methodologies. Technical conferences on these matters were held on January 21, 2002 and February 1, 2002. On February 13, 2002, we received the Final Amended Stipulation which was submitted by the Company on behalf of the Stipulating Parties.